Wires Down -- Vegetation

Primary Overhead Conductors

Injuries/Fatalities

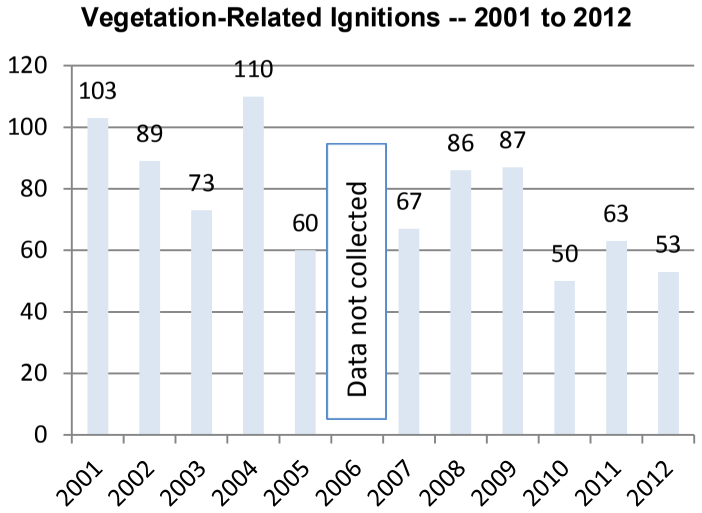
- 3 contacts as a result of a vegetation related wire down

Fire Ignitions

- Number of events is decreasing. Typical event involves less than 10 acres but the possibility of a catastrophic fire exists:
  - Southern California: 2008 Witch Creek, Guejito and Rice fires (SDG&E) and Malibu Canyon Fire (SCE)
  - PG&E: 2008 Whiskey Fire - 7,783 acres (Tehama county)
- The risk of catastrophic wild fire will be addressed as part the enterprise risk management assessment
- System Protection will have a separate risk assessment and will include a recommendation to review reclose relay settings in UWF/OWF/SBWF areas

Property Damage

- 4 property damage events due to vegetation related wire down



OH Primary Conductor Fires by Size 2007 to 2012

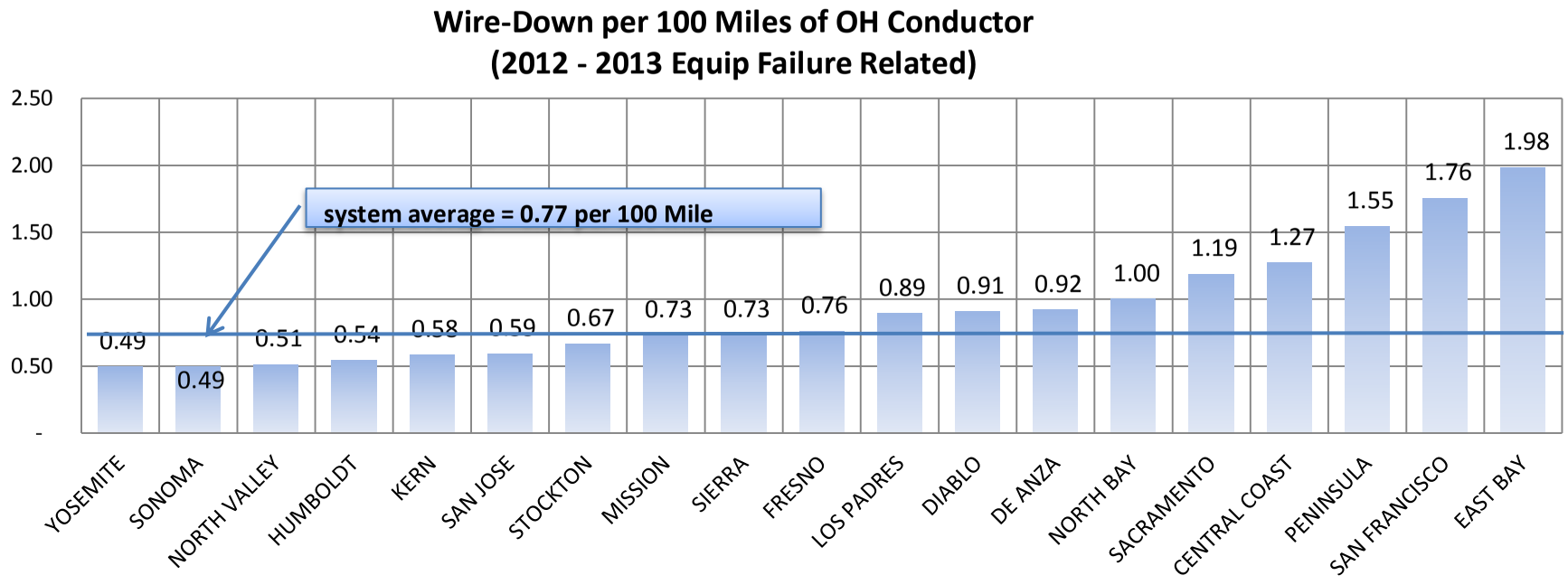
Fire Size	Number
≤ 10 acres	338
10 to 100 acres	9
100 to 1,000 acres	3
1,000 to 10,000 acres	1
> 10,000 acres	0
Total	351

1 acre ≈ 1 football filed

Wire Down -- Equipment Failure

Primary Overhead Conductors

- **The system average of wire down events due to equipment failure is 0.77 per 100 miles**
  - East Bay, San Francisco, Peninsula, Central Coast and Sacramento have values > 150% of the system average. Except for Sacramento, all the divisions have corrosion areas.



- Wire size, type and location are attributes

Equipment Related Wire Down - Attributes

Primary Overhead Conductors

Conductor Size

- ***Small wire*** (< 1/0) wire down rate is 9% higher than the system average (0.84 vs. 0.77)

Conductor Type

- The performance of ***copper*** conductor is significantly worse than the system value (1.15 vs. 0.77)

Corrosion Zone

- The performance of conductors in ***corrosion*** zones is worse than non-corrosion zones
  - 6 Cu is estimated to be 2.5 times higher in corrosion zone
  - 4 ACSR is estimated to be 13 times higher in corrosion zone
- The following divisions have corrosion zones
  - Humboldt
  - Sonoma
  - North Bay
  - Mission
  - East Bay
  - Peninsula
  - Central Coast
  - Los Padres
  - San Francisco
- Six of these divisions have wire down rates greater than the system average

Attributes That Potentially Increase the Consequences of a Wire Down Event

Primary Overhead Conductors

- Asset location is an attribute that increases the negative consequence of a wire down event
  - Wild Fire Area (Urban, Other, Santa Barbara)
  - Urban Population Areas (using GIS definition of 1,000 people/square mi)
  - Corrosion Areas
  - Major roadways and waterways

Estimated Amounts of Small Wire Sizes by Attribute

Attribute	# 6 Cu	# 4 Cu	Other Small Copper Conductors	Sub Total Copper	4 ACSR	2 ACSR	Sub Total ACSR	Total Small Conductor
Wild Fire Area	310	104	67	481	549	98	647	1,128
Urban Population Area	7,738	1,931	660	10,329	8,409	276	8,685	19,104
Corrosion Area	2,341	586	218	3,145	683	16	699	3,844

- Wire down events where conductor remains energized is another attribute that potentially increases the consequences of wire down events
  - Energized conductor data varies considerably between divisions. Improved data collection is needed
- Number of in-line connectors also influences likelihood of failure

Current Control Mitigations -- Intact Contact

Primary Overhead Conductors

- Vegetation Management
  - Routine trimming & removal (~ 1.3 million units/year)
  - 99.5 % compliance with regulatory requirements
  - Work at historic outage locations
  - Pilot analyzing failure characteristics of otherwise healthy trees in wildfire areas
- Design, Construction and Operating Requirements
  - Clearance requirements
  - Warning signs
- Overhead Line Maintenance Program
  - Visual patrols and inspections that can potentially identify issues such as excessive sag, inadequate clearances, vegetation problems, etc.
- Public Awareness Programs
  - Wire Down awareness
  - Tree Trimmers awareness
  - Need awareness program for specific third parties such as painters, roofers, cable, crane operators

Current Control Mitigations -- Wire Down Contact

Primary Overhead Conductors

Vegetation Management (see prior page)

Public Awareness Programs

- Wire Down awareness
- Tree Trimmers awareness

Design, Construction and Operating Requirements

- Bulletins addressing the use of 6 Cu and automatic splices
- Expanding corrosion area boundaries
- Review of minimum wire sizes
- Review of splices per span and application of shunt splices

OH Conductor Replacement Program

- Replaced 96 miles in 2013. 2014 plan is to replace 187 circuit miles (capacity and reliability programs)

Infrared and Splice Inventory Program

- Assessed 10,000 miles in 2013. 2014 plan to infrared and inventory splices on another 10,000 miles.

System Protection

- 2012 review concluded that PG&E's practices reflect what is currently considered good practice in the industry

- Line Maintenance Program
  - Visual patrols and inspections that can potentially identify issues such as excessive sag, inadequate clearances, vegetation problems, etc.
- 911 Response
  - Processes and metrics to respond in a timely manner to emergency situations

Current Controls Assessment - Amber

Primary Overhead Conductors

				Risk Drivers				
	Control Description	Frequency/Impact	Control Type	Third-Party	Equipment Failure	Vegetation	Work Procedure Error	Animal
	Public Awareness Programs (Wire Down/Tree Workers)	Frequency	Preventive (administrative)					
	Vegetation Management	Frequency	Preventive					
	Line Maintenance Program	Frequency	Preventive					
	Design, Construction and Operating Procedures	Both	Preventive (administrative)					
	Conductor Replacement Program	Frequency	Preventive					
	Infrared Inspection /Splice Inventory	Frequency	Preventive					
	Site Investigation (wire down, vegetation, work procedure)	Frequency	Preventive					
	System Protection (separate risk evaluation)	Impact	Detective					
	911 Response	Impact	Preventive					

Strong Control | Adequate Control | Weak Control

Recommendations – New Risk Mitigations

Primary Overhead Conductors

Work Recommended	Risk Driver Affected	Addresses Impact/ Frequency	Proposed Action Owner	Timing	Comments
Expand public safety outreach program to (1) focus on specific third parties such as painters, roofers, cable, crane operators beyond veg; (2) expanded metrics and reporting to ensure efforts are effective	3rd party	Frequency & Impact		Complete plan by Q2 2014	Coordinate with External Communications and Customer Care. Lower the risk of accidental contact with distribution conductors
Review tree trimming practices to explore opportunities to focus on historical wire down locations	Vegetation	Frequency		Complete Evaluation and Finalize Plan by Q2 2014	Final GRC decision will specify vegetation balancing account amount
Revise STAR Tool to assign additional risk to small and copper wires and locations with higher failure rates	Equipment	Frequency		Complete by Q2 2014	Address high consequence locations such as freeway crossing, from a impact potential, to better prioritize replacement or upgrades
Develop a plan, including quantities and schedules, to replace certain small wire (such as 4 Cu, 6 Cu & ACSR) in wild fire areas, urban areas and high corrosion areas.	Equipment Failure	Frequency		Plan: Q2 2014 Implement: Q3 2014	

Recommendations – New Risk Mitigations

Primary Overhead Conductors

Work Recommended	Risk Driver Affected	Addresses Impact/ Frequency	Proposed Action Owner	Timing	Comments
Electric distribution standards to issue guidelines for threshold limit on maximum number of in-line connectors on existing lines as well as criteria/driver for nominating OH wire for replacement.	Equipment Failure	Frequency		Complete Q1, 2014	Guidance on the allowable number of splices in new spans already exists.
Revisit existing distribution protection practices and explore potential application of new technology options to reduce likelihood of a down primary wire remaining energized. Prepare a report summarizing the findings and recommendations.	Third Party	Frequency & Impact		Complete Q2, 2014	

Prior to executing new recommendations, we find the current residual risk of ED OH Conductor is "amber". Upon implementation of proposed incremental controls and continuation of existing controls, we anticipate the future residual risk will continue to be "amber."

Risk Scenarios – Current Residual Risk

Primary Overhead Conductors

Typical result of an asset failure:
A service interruption to approximately 350 customers for approximately two hours (excluding major event days) and does not result in an electric contact or fire ignition.

Extreme result of an asset failure:
A conductor failure or tree contact causing:

(a) A relatively small (<1000 acres) fire in a densely populated area (e.g., Oakland Hills) resulting in significant property damage, fatalities and injuries; or

(b) A large fire in a rural area involving more than 100 square miles (approximately 64,000 acres) resulting in limited property damage but would include fatalities and injuries

These scenarios are used to score and prioritize our relative risk in the Risk Register for Electric Operations

Risk Evaluation Tool (7x7) scoring of scenarios:

	Risk Scenario	Frequency Level*	Impact Level*					
			Safety	Environmental	Compliance	Reliability	Reputational	Financial
Current Residual	Typical	7	1	1	1	3	1	1
	Extreme	3	6	6	5	4	6	5

*Definitions of ranking levels are based on the enterprise risk management 7x7 matrix v5.

Targeting locations using likelihood and consequence factors

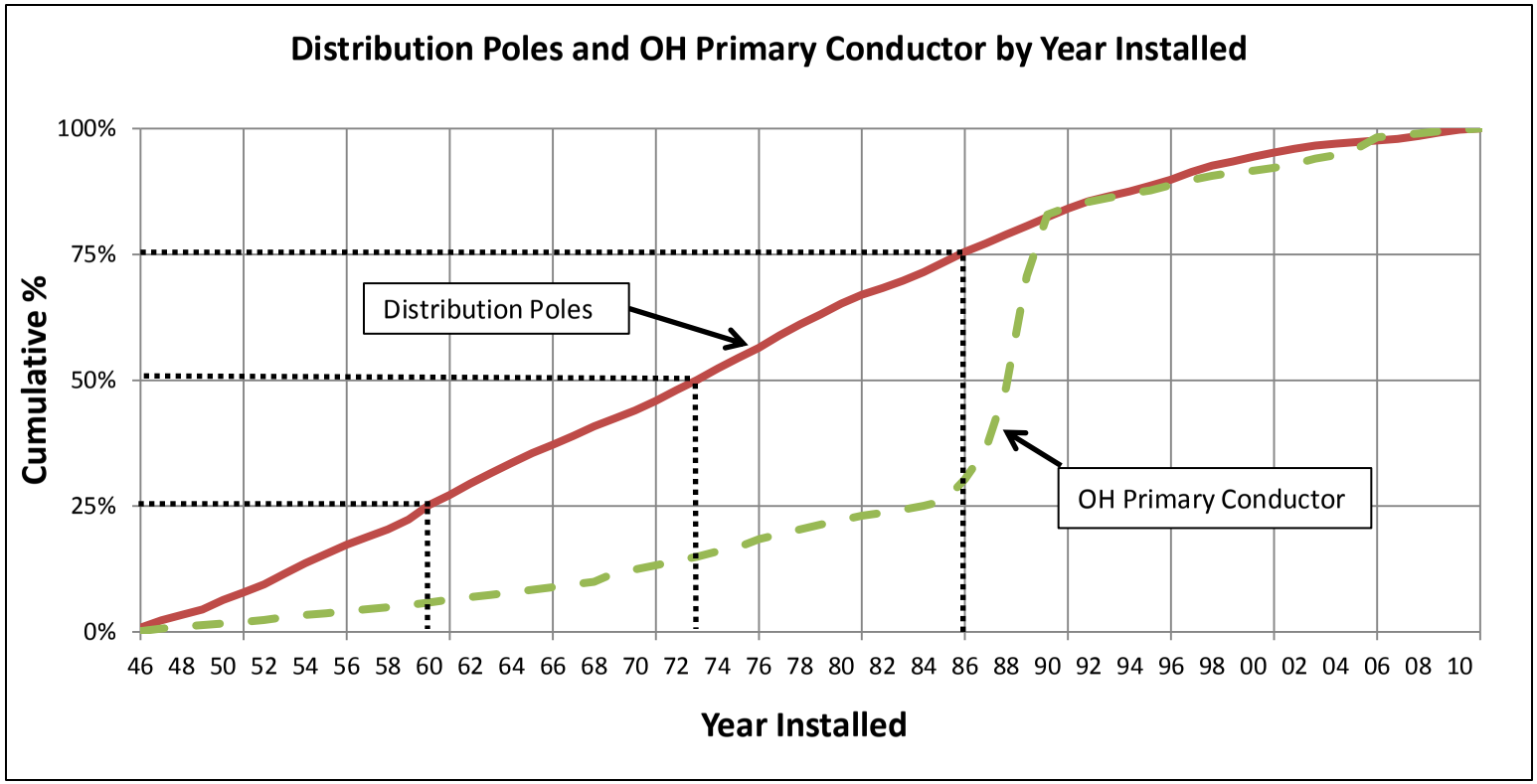
GIS Overlay of:

- Corrosion Zones
- Urban population density
- UWF/ OWF/ SBWF

Would need to overlay small copper distribution conductor on this, and adjust to show HCA versus strictly “urbanized areas”

Conductor Age Data

Primary Overhead Conductors



- Conductor age data in CEDSA is inaccurate – the significant increase in conductor amounts is a result of a technology system conversion in the late 1980's where the year installed field became mandatory and 1988, 1989 and 1990 was entered for many previously-blank line section records
- Using distribution pole age we can estimate that:
  - 25% of OH conductor is over 50 years old
  - 50% of OH conductor is 40 years old
  - 75% of OH is over 27 years old
- There is no age data for splices/connectors.

Asset Performance

Primary Overhead Conductors

- The tables below show sustained outages by:
  - ❑ Basic cause – which identifies leading risk drivers
  - ❑ Asset type – which is potentially useful in understanding performance from a conductor vs. connector/splice perspective

Sustained Outages by Basic Cause -- 2008 to 2012 (excluding major event days)

Basic Cause	2008	2009	2010	2011	2012	Total	5 Year Avg	% of Total
Vegetation	2,266	2,226	2,236	2,083	2,412	11,223	2,245	41%
Equipment Failure	2,505	2,155	2,037	1,956	2,133	10,786	2,157	39%
Third-party	508	496	503	570	586	2,663	533	10%
Animal	367	403	463	633	652	2,518	504	9%
Company Initiated	47	42	40	55	60	244	49	1%
Unknown cause	43	43	56	51	34	227	45	1%
Total	5,736	5,365	5,335	5,348	5,877	27,661	5,532	100%

The leading risk drivers are:

- ❑ Vegetation (41%)
- ❑ Equipment Failure (39%)
- ❑ Third-party (10%)
- ❑ Animal (9%)

Sustained Outages by Asset Type -- 2008 to 2012 (excluding major event days)

OH Asset Type	2008	2009	2010	2011	2012	Total	5 Year Avg	% of Total
Conductor, Overhead	4,646	4,359	4,412	4,466	4,830	22,713	4,543	82%
Connector or splice	350	340	345	358	450	1,843	369	7%
Jumper	724	653	566	517	589	3,049	610	11%
PG's, Kearneys	16	13	12	7	8	56	11	0%
Total	5,736	5,365	5,335	5,348	5,877	27,661	5,532	100%

- Personnel familiar with splice & connector performance and PG&E's data recording practices consider the splice/connector data inaccurate. Improved data in this area is necessary.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

GAS OPERATIONS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
GAS OPERATIONS

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CHAPTER 5
GAS OPERATIONS

A. Introduction

This chapter describes how Pacific Gas and Electric Company's (PG&E) Gas Operations organization is using the Enterprise and Operational Risk Management (EORM) Standard, its Integrity Management program, and other tools to manage gas system risks.

B. General Processes

1. Organizational Structure

Within Gas Operations, risk management is owned by the Risk Register, Asset Knowledge and Integrity Management, and Investment Planning departments.

- The Risk Register team is responsible for overseeing risk management activities driven by the EORM Program. This includes maintenance of Gas Operations' Risk Register and implementation of the Session D process.
- The Asset Knowledge and Integrity Management (AK&IM) Department is responsible for overseeing PG&E's Transmission Integrity Management Program (TIMP), Distribution Integrity Management Program (DIMP), and Facility Integrity Management Program (FIMP). These programs are driven by federal requirements[1] and involve risk management programs that are focused on asset-related threats and risks. The Senior Director of AK&IM is also accountable for the asset management planning processes within Gas Operations[2] and oversees the development of asset management plans for each of Gas

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1 TIMP is driven by Title 49 of the Code of Federal Regulations – Transportation (49 CFR) 192 Subpart O. DIMP is driven by 49 CFR 192 Subpart P. FIMP is a new concept that has been discussed as part of the Pipeline and Hazardous Materials Safety Administration's (PHMSA) proposed rulemaking related to the Integrity Verification Process.

2 Gas Operations' asset management activities are executed in line with the PAS-55/ISO-55001 Asset Management standard.

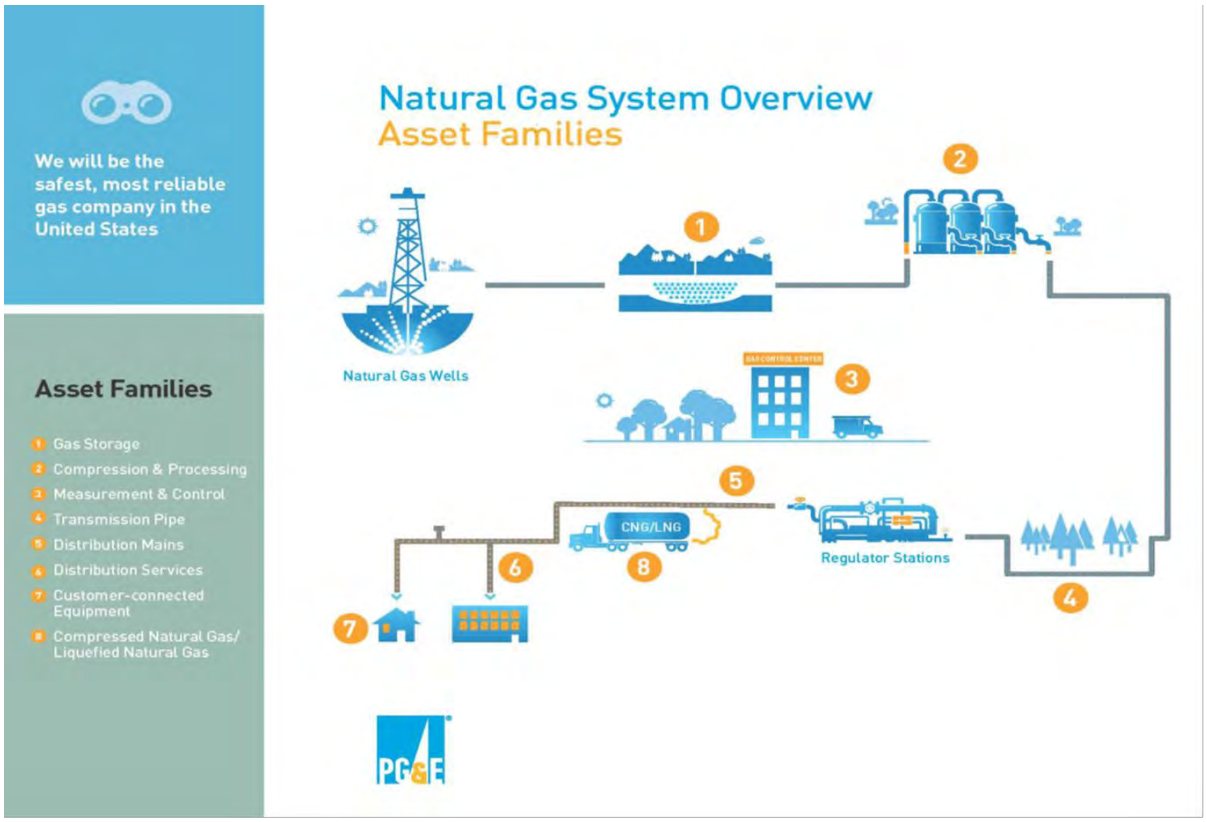
Operations' asset families. Asset families and asset management plans are described in more detail below.

- The Investment Planning team is responsible for overseeing Gas Operations' implementation of the Risk Informed Budget Allocation (RIBA) process described in Chapter 2.

In mid-2012, PG&E introduced a new paradigm into Gas Operations. PG&E divided its assets into families and designated an individual—the Asset Family Owner (AFO)—for each asset family who is accountable for managing the health of those assets.

PG&E has identified eight asset families within Gas Operations. These are outlined in Figure 5-1 below.

FIGURE 5-1
PACIFIC GAS AND ELECTRIC COMPANY
GAS OPERATIONS ASSET FAMILIES



Risks are identified and included in the Gas Operations Risk Register based on the asset family structure, and investment decisions are made

within and across asset families aligned with the investment planning, budgeting, and rate case frameworks.

In addition, Gas Operations implemented a new risk and asset management process and strengthened senior leadership oversight through its Risk and Compliance Committee (RCC). The RCC is chaired by the Executive Vice President, who appoints representatives from Gas Operations to participate on the committee. RCC members have a broad understanding of the business, its processes, and associated risks. The RCC meets monthly to review current risk-related topics and approve items such as risk assessments, risk mitigation measures and changes to the Risk Register.

2. Enterprise and Operational Risk Management and Integrated Planning Processes

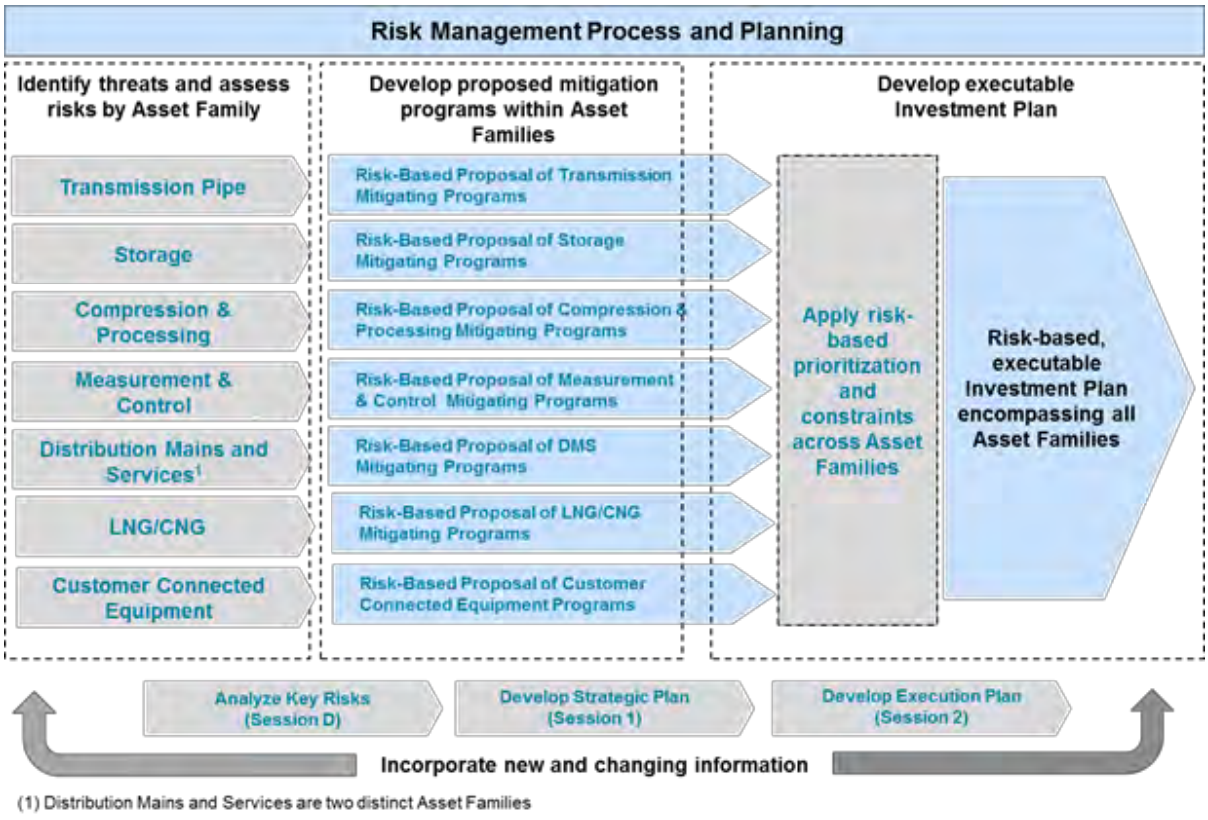
As described in Chapter 2, PG&E's EORM Program allows PG&E to manage assets and risks at both an enterprise and operational level. The enterprise risks are those that could threaten the viability of PG&E and typically span multiple lines of business (LOBs). Operational risks arise from assets, people, processes and technologies within specific LOBs, such as Gas Operations. By assessing and managing risks from both points of view, PG&E can better manage the interdependencies and drive for consistency among LOBs.

Gas Operations has adopted a risk management process that provides a repeatable and consistent method to identify, assess, rank and mitigate risk. This risk management process is fully integrated into PG&E's Integrated Planning Process to ensure risk informs the chosen strategies, which in turn drives the allocation of resources. Gas Operations has been advancing its risk management methodology over the last three years, and continues to (i) increase the rigor and documentation of the risk management process; (ii) use more data; (iii) expand the scope of risks assessed as part of the process; and (iv) improve consistency of risk scoring across Gas Operations.

The three phases of Gas Operations' risk management and planning process—(1) Identify threats and assess risks by Asset Family; (2) Develop proposed mitigation programs within Asset Families; and (3) Develop

executable Investment Plan—are aligned with the PG&E's Integrated Planning Process. The three phases are depicted in Figure 5-2.

FIGURE 5-2
PACIFIC GAS AND ELECTRIC COMPANY
RISK MANAGEMENT PROCESS AND PLANNING



Additional information on PG&E's Integrated Planning Process can be found in Chapters 1, 2 and 3.

3. Risk-Based Prioritization Methodologies

To support decision making in the Integrated Planning Process, Gas Operations uses several methodologies to prioritize programs and projects. Some examples of these approaches are outlined in this section.

a. DIMP

Federal regulations[3] require Gas Operators to develop an approach to ensure the integrity of its distribution system. PG&E's overarching DIMP framework is outlined in Figure 5-3 below:

FIGURE 5-3
PACIFIC GAS AND ELECTRIC COMPANY
DIMP CONTINUOUS IMPROVEMENT CYCLE

Consistent with other gas operators within California, PG&E uses a leak-based risk model to assess the risk of distribution pipelines. This model considers five years of historical leak data to identify geographical areas with elevated risk. A negative trend of leak repairs for a geographic area for each threat helps identify where additional mitigation may be applied.

The California Public Utilities Commission (CPUC) oversees DIMP and periodically performs audits in accordance with State and Federal

[3] 49 CFR, Part 192-Transportation of Natural and Other Gas by Pipeline: Minimum Federal Standards, Subpart P – Gas Distribution Pipeline Integrity Management.

Guidelines.[4] Some of the topics addressed in the audits include a review of how operators identify threats, perform risk evaluation, and identify mitigation.[5]

Each of the seven steps in PG&E's DIMP cycle is summarized below.

1) Know the PG&E System

System knowledge is the core foundation of DIMP and improves the overall safety and reliability of the distribution pipeline system. At the beginning of each DIMP cycle, the DIMP Mitigation and DIMP Risk teams review the data sources. Consideration is given to information gained from design records, operations, and maintenance as well as knowledge gained from the DIMP Steering Committee, which is comprised of members of the DIMP team and is supplemented with subject matter experts (SME) in each of the DIMP threat categories.

PG&E's DIMP Risk team uses the data, outlined in Figure 5-4, to provide a comprehensive dataset for risk evaluation. As shown in Figure 5-4, a majority of the data used is entered into SAP.[6] This data is entered by field personnel conducting leak surveys, excavation activities, or other field activities along the pipeline. PG&E uses 20 attribute data fields for its risk analysis.

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4 49 CFR 190.203 authorizes PHMSA to perform inspections. General Order 112-E refers to CFR 190 and PHMSA relegates its authority to the CPUC to oversee operators.

5 PHMSA Form 24 (192.1005-192.1011) Gas Distribution System DIMP Implementation Inspection, July 7, 2014, Rev 0.

6 SAP is PG&E's system of record for asset registry and work management.

FIGURE 5-4
PACIFIC GAS AND ELECTRIC COMPANY
PRIMARY AND SECONDARY DATA SOURCES FOR RISK ATTRIBUTES

Attribute	Primary Data Source	Secondary Data Source
Leak Number	SAP	n/a
Division	SAP	Pathfinder GIS
District	SAP	Pathfinder GIS
City	SAP	Pathfinder GIS
Line Use	SAP	Plat sheet
Leak grade	SAP	n/a
Reported Leak Cause	SAP	n/a
Leak Source	SAP	n/a
Material of Leaking Component	SAP (Pipe Data)	SAP (Inspection)
Pressure	SAP	SynerGEE
Diameter	SAP (Pipe)	SAP (Inspection)
Surface Over Pipe	SAP (Inspection)	SAP (Surface Over Read Location)
Repair Date	SAP	n/a
Proximity to Areas of Public Assembly	SAP	GIS Public Assembly Data
Employee and Other Injury	RiskMaster	SAP
Employee and Other Fatality	RiskMaster	SAP
Damage Cost	RiskMaster	SAP
Wall to Wall Paving	SAP	n/a
Injury/Fatality Metric	PHMSA	n/a
Injury/Fatality Ratio	PHMSA	n/a

Other data fields extracted from SAP are reviewed and help in determining appropriate mitigation activities.

2) Identify Threats

PG&E uses leak data and SME input for threat identification and risk evaluation. The DIMP Risk team reviews the collected dataset and assigns one of eight threat categories (identified in 49 CFR Part 192, Subpart P) to each leak. The DIMP Risk team then applies sub threats, which identify risk drivers and determines if accelerated actions are needed to mitigate risk.

Additionally, PG&E monitors potential threats. These threats are identified by data sources independent from leak repair

(Figure 5-5). This includes reviewing internal, industry and government data sources to generate a potential threat list which is annually reviewed and evaluated for risk. The identified potential threat list, its validity and any action required is reviewed and approved by the DIMP Steering Committee.

FIGURE 5-5
PACIFIC GAS AND ELECTRIC COMPANY
SOURCE DATA FOR MONITORING POTENTIAL THREATS

Database	Monitoring Interval
PHMSA Bulletins	Annually
National Transportation Safety Board Accident Reports	Quarterly
DIMP Field Review	As Performed
Material Problem Reports	Quarterly
Gas Corrective Action Plan Reporting	Quarterly
Potential Threat Log	Annually

3) Evaluate and Rank Risks

The risk assessment for the gas distribution system is informed from its leak history. In the assessment, each leak receives a score based on its Likelihood of Failure (LoF) and Consequence of Failure (CoF). The LoF for each leak is equal to 1 since the failure has already occurred. The CoF portion of the risk model is based on the following components: Impact on Life; Consequence Potential; Leak Magnitude; and Injury/Fatality statistics. Figure 5-6 outlines the variables considered in each of these components. The variables of each component are identified and the relative severity of a variable's points determines the contribution to the consequence of a leak.

FIGURE 5-6
PACIFIC GAS AND ELECTRIC COMPANY
RISK EVALUATION CONSEQUENCE FACTORS AND EQUATION

Impact on Life	Consequence Potential	Leak Magnitude	Injury Fatality
• Near Public • Injury • Fatality • Damage	• Wall to Wall Paving • Surface • Proximity	• Pipeline Pressure • Pipeline Diameter • Leak Grade	• Injury Fatality Metric • Injury Fatality Ratio
CoF = [(Impact on Life)+(Consequence Potential)]*[(Leak Magnitude)*(Injury Fatality)]			

As shown in the equation below, the total consequence associated with each threat is the sum of the applicable leak consequence scores.

$$RT = \sum_{i=1}^{n} LoFi \; X \; COFi$$

Where:
RT = Total risk per threat
N = Number of leak events
LoFi = Likelihood of each recorded leak event (equal to 1)
CoFi = Consequence of each leak event

The risk scores from this equation are aggregated by geographical area to develop a relative risk ranking of all threats and geographical areas.

Following the calculation of the risk scores, the DIMP Risk team analyzes risk at the appropriate level of aggregation for each threat. Excavation is a threat that varies at a local level, and therefore must be managed and mitigated at the local level. Because of this, PG&E separates out excavation threats from this analysis, and reviews this risk at the city level. Figures 5-7 and 5-8 below show the risk analysis done for excavation at the city level, and the analysis done for all other threats at the district (subset of a PG&E division) level. Values to the right of the vertical lines represent high risk, and the values within the two lines define medium risk areas.

FIGURE 5-7
PACIFIC GAS AND ELECTRIC COMPANY
RISK FOR EXCAVATION – CITY LEVEL

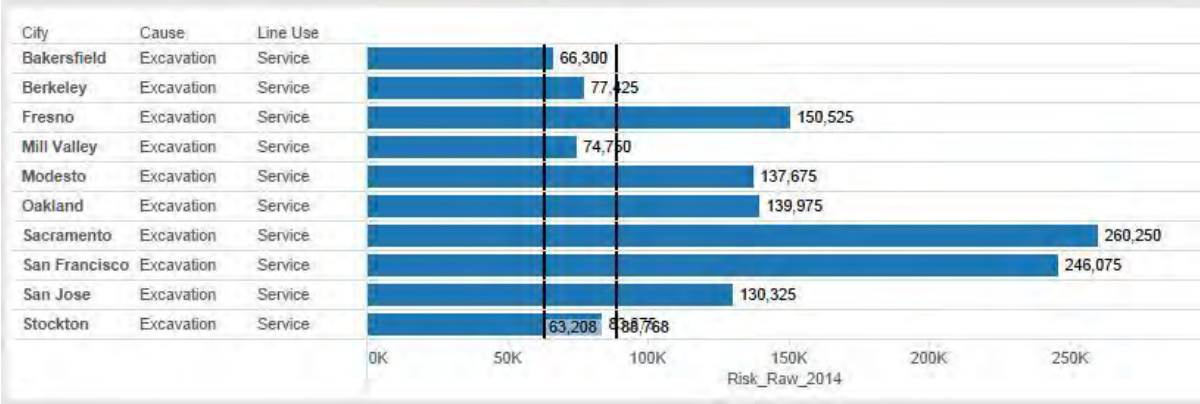
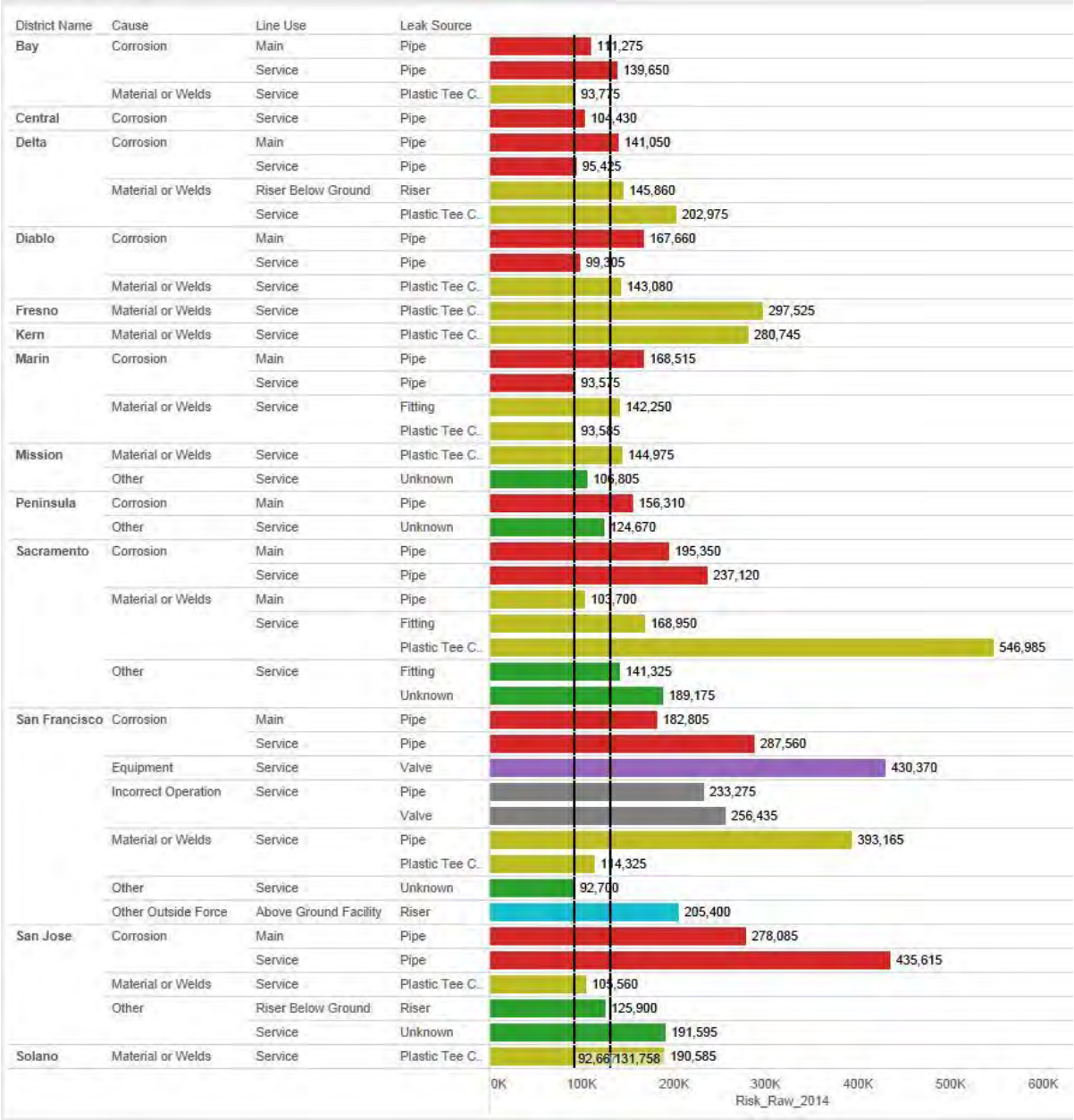


FIGURE 5-8
PACIFIC GAS AND ELECTRIC COMPANY
RISK FOR ALL CAUSES EXCEPT EXCAVATION – DISTRICT LEVEL



The DIMP Risk team uses standard deviations to define distribution bands in determining geographic areas of low, medium, or high risk for each of the two risk analyses shown in Figures 5-7 and 5-8.

System performance is identified based on a 5-year linear trend of leak repairs for the same geographic area for each threat. The leak data gathered (as summarized in Figure 5-4) is reviewed for

this analysis. Good performance is indicated by a decreasing 5-year linear trend. Fair performance is indicated by a flat (slope equals zero) 5-year linear trend. Poor performance is indicated by an increasing 5-year linear trend.

The combination of risk scores and system performance, outlined below, determine if a Root Cause Analysis (RCA) is needed. RCAs help determine the appropriate mitigation activities for each threat. PG&E performs RCAs in cases as shown in Figure 5-9.

FIGURE 5-9
PACIFIC GAS AND ELECTRIC COMPANY
NEED FOR ROOT CAUSE ANALYSIS DETERMINATION

		Performance		
		Good	**Fair**	**Poor**
Risk	**Low**	Review Next DIMP Cycle	Review Next DIMP Cycle	Review Next DIMP Cycle
	Medium	Review Next DIMP Cycle	Review Next DIMP Cycle	**Perform RCA**
	High	Review Next DIMP Cycle	**Perform RCA**	**Perform RCA**

4) Implement Measures to Address Risks

The DIMP Mitigation team considers all current and applicable mitigation measures. During this review the DIMP Mitigation team will identify new mitigation measures or changes to the program that will reduce risk.[7] If existing programs and activities do not adequately address the risk, the team will work to develop a new program or project to mitigate the risk. Program specific mitigation actions such as the Aldyl-A Replacement program and the Gas Pipeline Replacement Program are reviewed to ensure work is prioritized accordingly. These programs and projects are included in the Session 1 and Session 2 processes to be prioritized and funded accordingly.

[7] Order Instituting Rulemaking 15-01-008, issued March 18, 2015, provides criteria for replacement and repair based on leak grade. The process for determining mitigation may change as additional clarity is provided through the rulemaking.

5) Measure Performance, Monitor Results and Evaluate Effectiveness

In accordance with the program evaluation requirements,[8] PG&E performs reviews and evaluations annually. The review includes refreshing leak data to incorporate new risks into the risk management process. The process described above is applied to the refreshed data, and included in the risk prioritization of the gas distribution system. Additionally, the DIMP Risk team evaluates existing algorithms and statistical methodologies used to derive the overall risk score.

6) Conduct Complete Program Evaluations and Make Improvements

PG&E performs reviews and evaluations of its threat identification, risk analysis, and mitigation performance on a periodic basis. PG&E also participates in internal quality assurance audits as well as external audits performed by regulatory agencies to ensure the program is meeting legal requirements.

7) Report Results

PG&E communicates the status of its reviews to key internal stakeholders on an annual basis. Additionally PG&E completes the following PHMSA forms: PHMSA F 7100.1-1 (Annual Report Form)[9] and PHMSA F 7100.1-2 (Mechanical Fitting Failure Report Form).

b. Program-Specific Prioritization Methodologies

For most risk-based programs, it is necessary to have a prioritization methodology that allows for risk ranking at the granular asset level to allow for implementation of the program over multiple years while maximizing risk reduction in the short term. Each program has either a

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8 49 CFR, Part 192-Transportation of Natural and Other Gas by Pipeline: Minimum Federal Standards, Subpart P – Gas Distribution Pipeline Integrity Management, 192.1007(f).

9 PG&E provides a copy of PHMSA F 7100.1-1 to the CPUC with a report outlining the major mitigation programs and accomplishments of the program during the previous year.

relative risk calculation methodology including components related to likelihood of failure and consequence of failure, or a decision tree methodology that prioritizes projects into tranches of equivalent risk.

Below are some of the risk mitigation programs included in the Integrated Planning Process:

- Aldyl-A Replacement Program – replacement of Aldyl-A pipe based on vintage, material properties, leak history, and other factors.
- Gas Pipeline Replacement Program – replacement of cast iron and pre-1940 steel based on leak history, vintage, material properties, corrosion potential, and other factors.
- High-Pressure Regulator (HPR) Replacement Program – replacement of HPRs based on vintage, material properties, and other factors.

4. Gas Operations Integrated Planning Process

Gas Operations follows the PG&E Integrated Planning process for identifying risks, developing mitigation programs, and prioritizing work to address risks. The details of Gas Operations' approach to this process are outlined below.

a. Session D and Risk Register

Each AFO with the assistance of SMEs, is responsible for identifying the risks associated with their asset family and scoring each risk based on system knowledge, available data, and SME knowledge. The categorization and evaluation of threats and risks are driven by industry-adopted integrity management principles,[10] PG&E's obligation to serve—both in terms of ensuring reliable delivery of natural gas and increasing capacity to meet demand—as well as risks posed by an inadequate response to and recovery from emergencies.

As stated above, PG&E has strengthened and advanced its risk management methodology. By implementing the process improvements noted below, PG&E has been able to effectively identify and score risks within Gas Operations:

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[10] For transmission assets, threats follow American Society of Mechanical Engineers B31.8S. For distribution assets, threats follow 49 CFR 192 Subpart P.

- Greater Utilization and Integration of Data: Gas Operations has increased visibility into potential risks by integrating Corrective Action Plan (CAP) and process hazard analysis data into the risk identification and scoring processes.
- Increased Rigor and Documentation: SME input is used for identification and validation of risks. Additionally, SME review and sign-off is required for each asset family's risk register.
- Expanded Scope of Risk Assessment: Risks that fall outside the asset families' risk registers, such as Gas System Operations and Employee Qualification risks, are identified, scored, and calibrated against asset risks and are included in the Risk Register for Gas Operations.
- External Review: PG&E has leveraged the use of third-party industry experts to validate Gas Operations' risk methodology and scoring.
- Calibration of Risk: This is achieved through the consistent application and calibration of risk categories and the risk scoring across Gas Operations risks.

After identifying and scoring the risks, AFOs meet with the Gas Operations' Risk Register team to calibrate and validate ranking of each threat. The AFOs document this ranking in a Risk Register (Attachment A), which is updated and refined as additional information is obtained and evaluated. Gas Operations communicates its top risks (based on the Risk Register scoring) to PG&E leadership in Session D of the Integrated Planning Process. Each risk is evaluated to determine if existing mitigations are effectively managing the risk. During this step, the AFOs also identify any interdependencies with other LOBs to effectively manage the risk. As described below, to the extent that additional mitigations are necessary, asset management plans and work plans are built out in order to mitigate or reduce the risks.

In addition to the Session D effort, risk is also tracked within Gas Operations during monthly RCC meetings described above. At these meetings, AFOs highlight progress made on key risks and the status of those risks. Furthermore, all Gas Operations risks included in the Risk

Register are stored in the Enterprise Compliance Tracking System for further updates, review and reporting.

b. Session 1 and Risk Informed Budget Allocation

Based on the risks identified and scored during Session D, AFOs then analyze and develop the proposed scope and pace of mitigation programs. Each of the mitigation programs is designed to address the identified threats and risks within the asset families to reduce those risks. The AFOs submit the list of mitigation programs to the Investment Planning team for further assessment and prioritization using the RIBA process.

The RIBA risk scores are then used to develop the 5-year strategic investment plan for Gas Operations, which is submitted for consideration at the enterprise level as part of Session 1. Additional details about RIBA can be found in Chapter 3.

c. Session 2 and a Risk-Informed, Executable Work Plan

In Session 2, individual projects are identified within the programs identified in Session 1 and the RIBA framework is applied to assist in developing an executable plan and scope of work for the following year. The investment plan developed in Session 2 includes refinement and additional details to inform execution plans. After the total portfolio of proposed projects has been prioritized using a risk score, Investment Planning applies additional factors such as constraints to the total portfolio to ensure the work can be accomplished effectively. Constraints include, for instance, resource constraints such as availability of trained and qualified personnel, execution constraints such as the time necessary to obtain required permits, and system constraints such as the ability to deliver gas to customers while performing the total portfolio of work.

Investment Planning then works with the AFOs to finalize the proposed investment plan based on the risks and constraints identified. This process requires discussion and rationalization among mitigation programs across asset families.

C. Areas of Focus and Improvement

Gas Operations is exploring opportunities within its risk management processes to develop a more structured optimization model that can enhance prioritization based on risk, resource, budget, and system constraints as part of the integrated planning process. Gas Operations will also continue to improve asset data quality including integration of asset health condition assessments for more informed risk assessments. Additionally, data gathered from root cause analyses, CAP, quality assurance/quality control, monitoring of compliance activities, and audit findings will help drive more informed risk processes.

In addition, in 2013, PG&E began working on the Pathfinder Program which will establish a single database for gas distribution asset information. Pathfinder will provide a "system of record" for all gas distribution asset data to facilitate risk assessments required for DIMP and will provide the foundation for a new unified Geographic Information System (GIS)/SAP model for storing gas distribution asset data. Additionally, the DIMP team will be using Riskfinder, which is a set of tools that helps automate the gathering of additional data streams. Another tool embedded in Riskfinder is the Uptime tool, which performs GIS-based risk analysis. This data will be used by the DIMP team to drive risk decisions and identify appropriate mitigations.

The DIMP team will also be expanding their review to regulator stations and meter sets. Regulator stations can potentially impact the integrity of downstream assets. This provides additional data that the DIMP Team will use to identify threats, assign a risk scoring, and develop mitigation work.

By leveraging technology and developing more consistent risk methodologies for diverse assets, programs will be prioritized based on risk across the system by making an asset-to-asset comparison rather than prioritization occurring within individual programs. This change in methodology will allow PG&E to ensure the highest risk assets, regardless of asset type, are replaced first, thus maximizing risk reduction.

PG&E plans on additional benchmarking within and outside the industry to validate and enhance its risk management framework and process. PG&E will also continue to seek external review from industry experts and academic research teams to help its risk management process validation and improvement journey.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

ATTACHMENT A

GAS OPERATIONS RISK REGISTER

Gas Operations Risk Register (1/5)

#	Risk Name	Current Residual Risk Score
1	GO – Cybersecurity	811
2	TRA4 – Catastrophic Pipeline Failure – Manufacturing Related Defects	807
3	TRA1 – Catastrophic Pipeline Failure – External Corrosion	807
4	TRA8 – Catastrophic Pipeline Failure – Internal Corrosion	807
5	TRA3 – Catastrophic Pipeline Failure – Welding/ Fabrication Related – Pre-1962 Construction with Land Movement	806
6	STO16 – Internal Corrosion and/or Erosion – Pipeline	804
7	DMS45 – Incorrect Operations – Cross Bore in Urban Area	617
8	CP19 – Third Party/Mechanical Damage – Vandalism	596
9	CP22 – Weather Related/Outside Forces – Seismic (Manned)	596
10	DMS40 – Records Management – Distribution Mains and Services	591
11	TRA12 – Catastrophic Pipeline Failure – Weather Related and Outside Forces – Land Movement	579
12	MC32 – Weather Related/Outside Forces – Seismic	573
13	MC15 – Equipment Related – LoC Complex/ Simple Station	573
14	MC1 – Incorrect Operations – LoC LP Distribution	551
15	CP12 – Manufacturing Defects	551
16	CP8 – Welding/Fabrication Related	551
17	STO26 – Weather and Outside Forces – Seismic	551
18	MC16 – Equipment Related – LoC LP Distribution	548
19	CP6 – Incorrect Operations	548
20	GSO1 – Failure to Meet Core Customer Demand for Design Standard Abnormal Peak Day (APD)	537

#	Risk Name	Current Residual Risk Score
21	DMS39 – Excavation Damage, Third Party – Rupture Non At-Fault	406
22	TRA11 – Incorrect Operations – Over Pressurization	348
23	TRA9 – Stress Corrosion Cracking	326
24	Gas Compliance Performance Risk	316
25	MC14 – Welding/Fabrication – Overpressure Complex Station	313
26	MC10 – Incorrect Operation – Terminal/Large Complex	313
27	MC4 – Incorrect Operations – Complex Stations	313
28	MC6 – Incorrect Operations – Backbone (PLS) Stations	313
29	STO17 – External Corrosion – Pipeline	313
30	MC3 – Incorrect Operations – LoC Simple Stations	312
31	MC13 – Welding/Fabrication – LoC Simple Station	312
32	STO20 – Manufacturing – Pipeline	312
33	STO12 – Erosion – Meters	311
34	STO15 – Erosion – Valves	311
35	STO18 – Fatigue – All Segments	311
36	DMS42 – Incorrect Operations – Employee Qualifications	311
37	TRA16 – Equipment Related – Over-Pressure Event	311
38	MC18 – Equipment Related – LoC Complex/ Simple Station	311
39	MC36 – Equipment Related – Terminal/Large Complex	311
40	MC19 – Equipment Related – Backbone (PLS) Stations	311
41	DMS8 – Incorrect Operations – Cross Bore in Suburban Area	310
42	CP1 – External/Internal Corrosion	310
43	CP2 – External Corrosion – Under Pipe Insulation	310
44	CP10 – Internal Corrosion and Erosion	310
45	CP18 – Stress Cracking Corrosion	310
46	DMS5 – Material or Weld – Plastic (System Safety)	310

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Gas Operations Risk Register (2/5)

#	Risk Name	Current Residual Risk Score
47	TRA6 – Third Party/Mechanical Damage	310
48	STO3 – Construction by 1st and 2nd Party – Reservoir	310
49	STO30 – 1st, 2nd, 3rd Party – All Segments	310
50	CP5 – Manufacturing Defects – Pipe Quality	310
51	STO19 – Third Party Damage – Pipeline	310
52	DMS1 – Excavation Damage, Third Party – Rupture At-Fault Due to Mismarking by PG&E	308
53	CP7 – Incorrect Operations – Odorization	308
54	DMS14 – Natural Forces	245
55	CCE29 – Material	237
56	CCE30 – Material Traceability	237
57	DMS53 – Incorrect Operations (Workmanship Traceability)	235
58	GSO3 – Risk of Using Manual Operations	235
59	CP13 – Equipment Related – Electrical Systems	235
60	LNG18 – Third-Party Damage – CNG Trailer Transportation Incident	235
61	CCE31 – Other Outside Forces – Building and Meter Interaction	235
62	DMS15 – External Corrosion – Unprotected Steel Pipe	234
63	DMS23 – Material and Weld – Steel Installed Through the 1950s	234
64	CCE20 – Equipment – Indoor Meter Sets	234
65	DMS46 – Incorrect Operations – Applicant Installed Facilities	234
66	DMS4 – Internal Corrosion	234
67	DMS43 – Outside Force – Land Movement Due to Erosion or Subsidence	234
68	CCE7 – Equipment or Other Outside Force – End of Life Failure	234
69	DMS22 – Material and Weld – Composite Risers	234

#	Risk Name	Current Residual Risk Score
70	CCE11 – Natural Forces (Flood)	234
71	LNG15 – Third-Party Damage – NGV Tank Rupture	234
72	DMS54 – Other Outside Forces – Inaccessible Equipment	202
73	CCE33 – Other Outside Force – Inaccessibility to System	202
74	STO21 – Construction – Pipeline	191
75	STO29 – Third Party Damage – All Segments	184
76	DMS10 – Incorrect Operations – Regulator (Low Pressure)	184
77	MC30 – 3rd Party/Mechanical Damage – Vandalism	183
78	STO23 – Weather and Outside Force – McDonald Island	181
79	CP21 – Weather Related/Outside Forces – Seismic (Unmanned)	181
80	MC33 – BTU Heating Value	176
81	LNG25 – Equipment – CNG Injection Equipment Ops Failure (Safety)	175
82	MC25 – External Corrosion	175
83	DMS52 – Material Traceability	175
84	MC30.1 – 3rd Party/Mechanical Damage – Vehicular Damage	175
85	DMS38 – Outside Force – Land Movement Due to Creep	174
86	DMS51 – Co-Location of Gas and Electric Facilities	174
87	MC2 – Incorrect Operations – LoC HP Distribution	174
88	DMS37 – Overbuilds	174
89	CP29 – Equipment Related – Hinkley Non-Retrofit Compressor Reciprocating Engine	174
90	MC7 – Incorrect Operations – LoS LP Distribution	174
91	MC21 – Equipment Related – LoS LP Distribution	174
92	CCE5 – Material or Weld – Inadequate Customer Regulator Design	173
93	STO13 – Incorrect Operations – Valves	158

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Gas Operations Risk Register (3/5)

#	Risk Name	Current Residual Risk Score
94	TRA19 – Mechanical Damage – Electric Substation Damage	144
95	TRA21 – Material Traceability	144
96	MC34 – Records Management – Inadequate Records (P50)	143
97	TRA26 – Equipment Related – Component Failure (Drips, Fittings)	138
98	STO5 – Corrosion – Well Casing	114
99	STO31 – Stress Corrosion Cracking – Pipeline	108
100	STO10 – Incorrect Operations – Wells	107
101	STO11 – Erosion – Wells	107
102	TRA14 – Mechanical Damage – First and Second Party Damage	103
103	STO4 – Incorrect Operations – Reservoir	103
104	LNG24.0 – Equipment – LNG Vaporizer Operations Failure (Safety)	103
105	LNG17.0 – Third-Party Damage – LNG Tanker Parked (Safety)	102
106	LNG16 – Third-Party Damage – LNG Tanker Transportation Incident	102
107	MC29 – Internal Corrosion	98
108	MC28 – Stress Cracking Corrosion	98
109	STO22 – Weather and Outside Force – LM and PC	98
110	MC12 – Welding/Fabrication – Overpressure Event (System Safety)	98
111	MC17 – Equipment Related (System Safety)	98
112	MC9 – Incorrect Operations (System Safety)	98
113	MC22 – Equipment Related – LoS HP Distribution	98
114	TRA23 – Third Party/Mechanical Damage – Vandalism	97
115	LNG26 – Third-Party Damage – ORCA Trlr Transpo Incident	97

#	Risk Name	Current Residual Risk Score
116	STO25 – Equipment – Storage Field Facilities	95
117	TRA22 – Incorrect Operations	82
118	LNG12 – Third-Party Damage – Fueling Station Drive Away	74
119	LNG24.1 – Equipment – LNG Vaporizer Outage (Reliability)	72
120	GSO9 – Scheduling Risk	68
121	CP15 – Records Management (P50)	68
122	TRA20 – Weather Related and Outside Forces – Tree Damage	58
123	TRA10 – Weather-Related Outside Force – Water Crossings and Exposed Pipe	58
124	CP24 – Hinkley Station Non-Retrofitted Compressor Outage Due to Any Cause	53
125	CP25 – Delevan Station Compressor Outage Due to Any Cause	53
126	CP32 – Santa Rosa Station Compressor Outage Due to Any Cause	53
127	CCE13 – Natural Forces (Seismic)	50
128	CCE32 – Other Outside Force – Spatial Clearance	45
129	CP9 – Equipment Related – Air Emission Regulation	44
130	STO20.1 – Manufacturing – Pipeline	43
131	LNG31 – Insufficient Portable Equipment	42
132	CCE4 – Other Outside Force – Third Party Damage – Construction and Redevelopment	41
133	STO27 – Incorrect Operations – Storage Field Facilities	39
134	TRA25 – Equipment Related – Inoperable Valves	38
135	DMS47 – Other Outside Forces – Tree Root Damage to Plastic Pipe	34
136	STO16.1 – Internal Corrosion and/or Erosion – Pipeline	34
137	CCE26 – Equipment Failure – Meter/Regulator	33

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Gas Operations Risk Register (4/5)

#	Risk Name	Current Residual Risk Score
138	LNG30 – Incorrect Operations – Station Documentation Safety	32
139	LNG32.0 – Equipment – Station Compressor and Component (Safety)	32
140	LNG19.0 – Third-Party Damage – CNG Tube Trailer Parked (Safety)	32
141	DMS50 – Military Facilities	31
142	LNG27 – Third-Party Damage – ORCA LNG Safety Parked	31
143	LNG32.1 – Eqpmt – Combined Sta Compr and Component (Reliability)	30
144	GSO2 – Failure to meet Non-Core CWD Design Standard	30
145	DMS44 – Excavation Damage – Unlocatable Stubs	30
146	LNG28 – LNG Commodity Shortfall	30
147	STO14 – Equipment – Valves	30
148	MC23 – Equipment Related – LoS Simple Station	29
149	MC26 – Manufacturing Related Defects	28
150	STO2 – Construction by 3rd Party – Reservoir	28
151	LNG29 – CNG Commodity Shortfall (Reliability)	28
152	STO31.1 – Stress Corrosion Cracking – Pipeline	28
153	CP4 – Weather Related/Outside Forces – Flooding (System Safety)	25
154	CCE2 – Other Outside Force – Third Party Damage – Vehicles	25
155	CCE6 – Material or Weld – Poor Quality Control of Regulator/Meter Set Manufacturing	25
156	LNG30.1 – Incorrect Station Ops	25
157	CP23 – Kettleman Station Compressor Outage Due to Any Cause (System Safety)	24

#	Risk Name	Current Residual Risk Score
158	CP26 – Tionesta Station Compressor Outage Due to Any Cause (System Safety)	24
159	CP27 – Burney Station Compressor Outage Due to Any Cause (System Safety)	24
160	CP28 – Gerber Station Compressor Outage Due to Any Cause	24
161	CP31 – Bethany Station Compressor Outage Due to Any Cause	24
162	CP33 – Topock Station Compressor Outage Due to Any Cause	24
163	CCE28 – Other Outside Force – Grounding	24
164	LNG22 – Incorrect Operations – CNG Quick Change Bottle Safety	24
165	GSO6 – Market Liquidity Risk	23
166	GSO8 – Demand Risk	23
167	LNG19.1 – Third-Party Damage – CNG Tube Trailer Parked (Reliability)	23
168	MC24 – Equipment Related – LoS Complex Station	22
169	MC27 – Equipment Related – Terminal/Large Complex	22
170	MC35 – Equipment Related – Backbone (PLS) Stations	22
171	STO30.1 – 1st, 2nd, 3rd Party – All Segments	22
172	STO24 – Weather and Outside Forces – McDonald Island	20
173	DMS2 – Excavation Damage Third Party, No Rupture (P50)	19
174	CP30 – Incorrect Operations	18
175	CP17 – Equipment Related – Deferred maintenance	18
176	DMS41 – Incorrect Operations – Fusion Joints (P50)	18
177	STO33 – Disposal Well – Gill Ranch	17
178	STO34 – Internal/External Corrosion – Disposal – Well – Gill Ranch	17

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Gas Operations Risk Register (5/5)

#	Risk Name	Current Residual Risk Score
179	STO17.1 – External Corrosion – Pipeline	17
180	GSO4 – Loss of Supply from Interconnected Pipelines and Third Party Storage	14
181	DMS12 – Material or Weld – Mechanical Fittings	14
182	CP23.1 – Kettleman Station Outage Due to Power Outage	14
183	LNG17.1 – Third-Party Damage – LNG Tanker Parked (Reliability)	13
184	DMS3 – External Corrosion on Steel Piping	12
185	DMS49 – Material or Weld – Isolation Valve Failure	11
186	GSO5 – Portfolio Management Risk	11
187	STO5.1 – Corrosion – Well Casing	11
188	STO1– Third Party Damage – Reservoir	10
189	LNG14 – Third-Party Damage – Fuel Theft	10
190	DMS25 – Material and Weld – Curb Valves	10
191	CCE23 – Natural Forces – Settlement of Soil	10
192	DMS11 – Incorrect Operations – Regulator (Semi-High or High Pressure)	10
193	MC20 – Equipment Related – LoS Complex/Simple Station	10
194	CCE16 – Other Outside Force – Inoperable or Inaccessible Service Valve	9
195	DMS7 – Natural Forces – Cast Iron Material	8
196	GSO7 – Price Risk	8
197	DMS48 – Internal Corrosion – Mainline Drips	7
198	CCE21 – Other Outside Force – Fire	7
199	CCE1 – Incorrect Operations	7
200	MC8 – Incorrect Operation – Terminal/Large Complex	6
201	MC5 – Incorrect Operations – Backbone (PLS) Stations	6
202	TRA2 – External Corrosion (P50)	6

#	Risk Name	Current Residual Risk Score
203	TRA7 – Third Party/Mechanical Damage (P50)	6
204	MC11 – Incorrect Operations – LoS Complex/Simple Station	5
205	LNG13 – Third-Party Damage – Dispenser Vandalism	4
206	LNG20 – Third-Party Damage – CNG Bottle Trlr Transpo Incident	4
207	DMS17 – Atmospheric Corrosion	3
208	CCE3 – Other Outside Force – Vandalism	3
209	TRA15 – Internal Corrosion (P50)	3
210	DMS6 – Material or Weld – T-Caps	2
211	TRA5 – Manufacturing Related Defects (P50)	2
212	LNG21 – Third-Party Damage – CNG Bottle Trlr Parked Collision (Safety)	1
213	STO35 – Outside Forces (Geological) – Reservoir	1
214	GSO10 – Risk of Multiple Clearances in the Same Gas System	0
215	GSO11 – Inadequate Visibility into the Pressures and Flows on the Networks	0
216	GSO12 – Gas Control Operator Error	0
217	GSO13 – SCADA Outage	0
218	GSO14 – Physical Security – Gas Control Center Attack	0
219	GSO15 – GOC System Failure Effecting Field Coordination and Response	0
220	MC8.1 – Incorrect Operations (System Safety)	0
221	MC10.1 – Incorrect Operations (System Safety)	0

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

RISK LEXICON

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CHAPTER 6
RISK LEXICON

This chapter provides a Risk Lexicon (Attachment A) that was developed in collaboration with the other utilities participating in this proceeding. The Lexicon includes terms that are used in risk management activities. Pacific Gas and Electric Company (PG&E) views this Lexicon as a potentially valuable tool that can assist in facilitating the discussion of risk and risk management.

PG&E's opinion is that this Lexicon should be viewed as a living document that can be added to and modified over time. To this end, PG&E proposes that this Lexicon, and other terms as well, be made the subject of a workshop in this Safety Model Assessment Proceeding. PG&E also proposes that the Commission publish the Lexicon in a manner that provides for easy public access and use, and that it be updated periodically.

Finally, there are two caveats that PG&E wishes to identify. First, it is not always possible or practical to agree on only one definition for a term. The same term is sometimes used somewhat differently in different companies or even within the same company. Thus, it may be advisable in some circumstances to publish more than one definition for a term. Second, the Commission should not mandate the use of a particular definition or consider any penalties for the "misuse" of a term. Rather these definitions should only be viewed as a tool with educational value that over time will promote a common language about risk management.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT A

RISK LEXICON

CHAPTER 6
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RISK LEXICON

Overview

Based on the Refined Straw Proposal's recommendations, PG&E, SCE, and Sempra have developed a set of core key risk terms and definitions to be used "for defining, acquiring, and disseminating risked-based information,"[1] known as the Risk Lexicon. The Risk Lexicon consists of a common set of terms and definitions to allow for ease of communicating the risk-management activities described in this filing. In addition to this set of core terms, each of the utilities may have additional risk terms and definitions to describe their specific processes. As with the other tools, we expect the Risk Lexicon to evolve as the ERM programs mature.

To develop the Risk Lexicon, PG&E, SCE, and Sempra looked first to the terms and definitions in the ISO 31000 and DHS Risk Lexicon terminology documents. The defined terms were further validated amongst a broader list of external sources common in the risk community to ensure consistency. Below is the defined list of key terms developed for the Risk Lexicon.

Terms	Definitions
Alternatives Analysis	Evaluation of different alternatives available to mitigate risk
Control	Currently established measure that is modifying risk
Current Residual Risk	Risk remaining after current controls
Enterprise Risk Management	Comprehensive approach to risk management that engages organizational systems and processes together to improve the quality of decision making for managing risks in order for an organization to be able to achieve its objectives

1 Refined Straw Proposal, p. 10.

Terms	Definitions
Event	Occurrence or change of a particular set of circumstances
Frequency	Number of events generally defined per unit of time
Impact (or Consequence)	Result of an event, incident, or occurrence affecting objectives
Mitigation	Measure or activity taken prior to the occurrence of an event, designed to reduce impact and/or frequency of an event
Planned Residual Risk (or Forecasted Residual Risk)	Risk remaining after implementation of proposed mitigations
Risk	Potential for an event that can impact company's ability to achieve its objectives
Risk-based Decision Making	Determination of a course of action predicated primarily on the assessment of risk and the expected impact of that course of action on that risk
Risk-informed Decision Making	Determination of a course of action predicated on the assessment of risk, the expected impact of that course of action on that risk, as well as other relevant factors
Risk Assessment Process	Overall process of risk identification, risk analysis and risk evaluation
Risk Driver (or Risk Trigger)	Factor(s) that could cause risk to occur
Risk Response Plan (or Mitigation Plan)	Collection of Mitigations
Risk Score	Numerical representation of a quantitative and/or qualitative risk evaluation methodology
Risk Taxonomy	A structure used to classify different types of risks across the company at multiple levels of aggregation

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ERIC BACK

Q 1 Please state your name and business address.

A 1 My name is Eric Back, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the director of the Compliance & Risk Management organization within Electric Operations.

Q 3 Please summarize your educational and professional background.

A 3 I am the director for Risk Management, Compliance, and Vegetation Management in Electric Operations. I joined PG&E in 2008 and worked in the Utility Performance Improvement group focusing on electric transmission and substation facilities and processes. Since then, I have been a substation maintenance superintendent and a director in Transmission Operations. Prior to joining PG&E, I worked in management and operations consulting. I am a registered professional engineer in the state of California. I have a bachelor of science degree in mechanical engineering from University of California, Davis, a master of science degree in mechanical engineering from Colorado State University and a master in business administration degree from the London Business School.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring Chapter 4, “Electric Operations and Nuclear Power Generation,” with the exception of Sections B.2. and C.2., in PG&E’s S-MAP proceeding. Sections B.2. and C.2. relate to the risk processes and programs at PG&E’s nuclear facilities and are sponsored by Cary D. Harbor.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF CHRISTINE C. CHAPMAN

Q 1 Please state your name and business address.

A 1 My name is Christine C. Chapman, and my business address is Pacific Gas and Electric Company, 6111 Bollinger Canyon Road, San Ramon, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 As senior director of Asset Knowledge and Integrity Management, within Gas Operations, I am responsible for the leadership and oversight of an organization focused on assessing the integrity of the transmission, distribution, and facilities assets utilizing traceable, verifiable, and complete asset knowledge and technological tools. I am also responsible for the development of a strategic integrity management plan for the entirety of these assets. In addition, I oversee Gas Operations' Research and Development Program.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in mechanical engineering from University of California, Berkeley and a master's degree in business administration from UC Berkeley, Haas School of Business. I am also a registered professional mechanical engineer in the state of California.

I started with PG&E in 2001 as a summer intern in the gas distribution organization and after graduating from UC Berkeley began a full-time position as a gas engineer. Since then, I have held a variety of positions with increasing levels of responsibility in the Gas Engineering and Operations organization, mainly focused on gas distribution functions.

In 2008, I transitioned to PG&E's Human Resources Department where I held various leadership roles. I returned to Gas Operations in January 2012 as the director of Distribution Integrity Management. In November 2013, I transitioned to the director of Transmission Integrity Management, and in May 2014, I was promoted to the senior director of Asset Knowledge and Integrity Management.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring Chapter 5, “Gas Operations,” in PG&E’s S-MAP proceeding.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF CARY D. HARBOR

Q 1 Please state your name and business address.

A 1 My name is Cary D. Harbor, and my business address is Pacific Gas and Electric Company, Diablo Canyon Power Plant.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the director of Compliance, Alliance and Risk for the Diablo Canyon Power Plant; in this capacity I am responsible for company compliance and risk program oversight, matrixed organizations including business finance and supply chain, and the PG&E management council representative to the STARS LLC.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in nuclear engineering from University of California, Santa Barbara, California, in 1989. I joined PG&E in 1989 as a power production engineer in the Engineering Department. I have since held positions as the supervisor of Regulatory Services, operations shift foreman/manager (senior reactor operator licensed by the Nuclear Regulatory Commission), performance improvement manager, quality verification director, and the Maintenance and Construction Services director. Most recently I became the director of Compliance, Alliance and Risk in 2012.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring Sections B.2. and C.2. of Chapter 4, “Electric Operations and Nuclear Power Generation,” in PG&E’s S-MAP proceeding.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JANAIZE MARKLAND

Q 1 Please state your name and business address.

A 1 My name is Janaize Markland, and my business address is Pacific Gas and Electric Company, 111 Stony Circle, Santa Rosa, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the director of PG&E's Enterprise and Operational Risk and Insurance Department. My department is responsible for overseeing PG&E's Enterprise and Operational Risk Management (EORM) Program and for procuring insurance to transfer PG&E's residual financial risks that could result from catastrophic property or casualty losses.

Q 3 Please summarize your educational and professional background.

A 3 I earned a bachelor of science degree in chemistry from the University of British Columbia and a master of science degree in Environmental Management from Royal Roads University in Victoria, British Columbia.

I am a member of the Enterprise Risk Management Utilities Roundtable and serve as chair of the Edison Electric Institute Enterprise Risk Management Task Force Steering Committee.

Prior to my career in the EORM and Insurance Department, I held a variety of roles at PG&E, including manager of Compliance and Ethics and positions in the Safety and Shared Services organization, where I provided direct environmental compliance support to PG&E's operating units. Before joining PG&E, I worked at BC TEL, a telephone utility based in Burnaby, British Columbia, and its successor company, Alberta-based TELUS Corporation, where I developed an environmental program governing the newly merged companies.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's S-MAP proceeding:

- Chapter 2, "Companywide Models and Approaches for Assessing Risk."
- Chapter 6, "Risk Lexicon."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JAMIE L. MARTIN

Q 1 Please state your name and business address.

A 1 My name is Jamie L. Martin, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I currently hold the position of director of Economic and Project Analysis. In this capacity, I supervise:

- Financial analysis and economic evaluations concerning a range of investment matters.
- The Risk Informed Budget Allocation process as part of the Company's Integrated Planning Process.
- Business case guidance and reviews of major capital project proposals.

I report to the Vice President, Finance, of PG&E.

Q 3 Please summarize your educational and professional background.

A 3 I graduated from the University of San Francisco, in 2004, with a bachelor of science degree in finance. I joined PG&E in 2007 as a senior business analyst in the Finance organization, specifically in Project Finance. I have since held a succession of positions in the finance organization. In 2009, I was promoted to supervisor in the Gas & Electric Transmission and Distribution Business Finance organization, responsible for operational financial planning, budgeting and forecasting. In 2010, I was promoted to manager in the Power Generation Business Finance organization, where I was responsible for managing a team that supported operational financial planning, budgeting and forecasting. In 2012, I completed a 6-month rotation as manager of Investor Relations, where I was responsible for communication with the investment community and prepared senior leadership for quarterly earnings calls and expectations for future performance. In late 2012, I became manager of the Financial Forecasting & Reporting team, where I was responsible for enterprise-level earnings forecasts, year-over-year and long-term budgets and forecasts, functional

area income statement analysis and board of director financial materials. I assumed my current position in March 2014.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring Chapter 3, “Companywide Models and Approaches to Risk Informed Budget Allocation,” in PG&E’s S-MAP proceeding.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SHELLY J. SHARP

Q 1 Please state your name and business address.

A 1 My name is Shelly J. Sharp, and my business address is Pacific Gas and Electric Company, 77 Beale, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am currently the senior director, General Rate Case and Regulatory Support. My responsibilities include overseeing the development of General Rate Cases (GRC) as well as various other applications before the California Public Utilities Commission, ensuring compliance with items from prior GRCs, and directing the efforts of PG&E's regulatory support functions.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a bachelor of science degree in business administration/ finance from California State University, Sacramento, in 1984. In 1985, I graduated from Golden Gate University in San Francisco, with a master's degree in business administration/finance.

I joined PG&E in 1985. From 1985 until 1997, I held various analyst and supervisory positions within the regulatory area including: regulatory affairs analyst, rates analyst, resource analyst, supervisor – Gas Rates, and manager – Electric Rates. In 1997, I took over as the director of the Rates Department, responsible for both gas and electric revenue allocation and rate design. In 2003, I became the director of Billing, Revenue and Records. In 2007, I became the senior director of Service and Sales in the Customer Care organization. In February 2008, I became the senior director of Customer Field Service within the Customer Care organization.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring Chapter 1, "Overview and Summary," in PG&E's S-MAP proceeding.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.